BOSTON EDISON COMPANY
CAMBRIDGE ELECTRIC LIGHT COMPANY
COMMONWEALTH ELECTRIC COMPANY
d/b/a
NSTAR ELECTRIC

REBUTTAL TESTIMONY OF HENRY C. LAMONTAGNE

D.T.E. 03-121

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Henry C. LaMontagne. I am Director of Regulatory Policy and Rates for the regulated operating companies of NSTAR. My business address is One NSTAR Way, Westwood, MA.

Q. On whose behalf are you submitting testimony in this proceeding?

A. I am submitting testimony on behalf of Boston Edison Company ("Boston Edison"), Cambridge Electric Light Company ("Cambridge") and Commonwealth Electric Company ("Commonwealth") (together "NSTAR Electric" or the "Company").

Q. Did you previously file testimony on behalf of NSTAR Electric in this proceeding?

A. Yes. On January 16, 2004, I submitted prefiled direct testimony on behalf of the Company supporting the seven standby and supplemental distribution service tariffs schedules filed for approval in this case.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony addresses issues raised in the rebuttal testimony of Alvaro Pereira, filed by the Massachusetts Division of Energy Resources ("DOER"); Sean Casten, Thomas Smith and Spiro Vardakas, on behalf of the

New England Distributed Generation Coalition ("NEDGC"); Mark Lively, on behalf of the Joint Supporters, DOER and the Conservation Law Foundation ("CLF"), David Hannus, on behalf of the Joint Supporters; Thomas Michelman, on behalf of CLF and the Solar Energy Business Association of New England ("SEBANE"); Andrew Greene, on behalf of SEBANE; and Elaine Saunders, on behalf of The Energy Consortium.

II. STANDBY RATE ISSUES

Q. Please summarize the Company's proposed Standby Service Rates.

A. The Company has proposed Standby Service rates that are designed to provide cost-based standby service for large and medium-sized commercial and industrial customers who have their own on-site, self-generation facilities. The standby tariffs provide customers with firm distribution and optional generation services (i.e., default service) to supplement and/or to replace temporarily customers' generation resources. Consistent with the Department's Order in Distributed Generation, D.T.E. 02-38, at 4 (2002), the Company's proposed tariffs accomplish the following goals: (i) ensure that standby customers pay an appropriate share of distribution costs; (ii) ensure that prospective standby customers receive accurate price signals so that they can properly decide whether to install distributed generation ("DG"); and (iii) prevent the shifting of costs from those who purchase standby service to other customers.

Q. Do the intervenors' witnesses raise issues concerning the Company's proposed standby rates?

A. Yes. In my testimony, I will respond to the following broad concerns raised by the Intervenors' witnesses:

1. The Company's proposed standby rates will reduce the savings that would otherwise be available to investors in DG.
2. The Company's proposed standby rates lack the necessary load research data and recent cost-of-service studies to support the proposed rates.
3. The Company's proposed standby rates include a ratchet and other objectionable rate design components.
4. The Company's proposed standby rates include various undesirable terms and conditions.
5. The Company should permit "grandfathering" for certain customers and other exemptions to support the renewable energy industry.

Q. Before responding to each of these concerns, please address the general argument made by some intervenors concerning the cost basis used to develop NSTAR Electric's standby rates.

A. Some intervenors, such as Mr. Pereira, testifying for the DOER, and Elaine Saunders, testifying on behalf of The Energy Consortium, have suggested that NSTAR Electric's proposed standby rates: (i) wrongly recover revenues without the customer having actually received any electricity through NSTAR Electric's distribution system; and (ii) are not based on an accurate accounting of the distribution and transmission costs that are needed to provide standby service to distributed generation customers. Both claims are without merit.

As explained in the rebuttal testimony of Mr. Salamone, the distribution system needed to serve all firm distribution customers, *including DG standby* *customers*, must be in place and instantaneously "ready" to serve all of the customers that are on-line within the appropriate section of the Company's distribution system. The costs of the Company's distribution system attributable to providing standby service are largely fixed (i.e., they do not vary based upon actual kWh use by the customer), and do not vary between a customer that takes all of its electricity requirements over the distribution system and a customer that uses DG to provide a portion of its electricity requirements, but requires firm standby service. Although the costs are the same to serve both types of customers, a DG customer might take service only infrequently. Therefore, the as-used energy and demand charges applicable to continuous-use service do not provide sufficient revenues to cover the costs when applied to standby service. As a result, the Company has proposed to recover certain distribution costs from standby customers based on contract-demand, which is a reasonable means of recovering the fixed costs that are incurred to provide firm standby service, whether or not the customer actually calls upon the Company's distribution system in any given month.

Q. What about the charge made by some intervenors that the Company's standby rates are not based on an accurate accounting of the distribution and transmission costs that are needed to provide standby service to distributed generation customers?

A. This contention is also without merit. Although rates, including the Company's existing commercial and industrial rates, in theory, are designed to recover the actual costs to serve the particular rate class to whom they are available, the

Department's longstanding ratemaking policy is intended to balance a number of important goals, including rate continuity, efficiency, simplicity, fairness between rate classes and corporate earnings stability. See Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 252 (2002). The Company's development of its rates for standby service are based on each of these principles, and assure a fundamental level of fairness between the level of costs that are the responsibility of standby customers and the otherwise applicable rate classes which, rather than generating their own electricity, obtain some or all of their electricity from on-site generation. In this manner, a consistent framework will be in place to serve all customers on the Company's system, including DG customers.

STANDBY RATES EFFECT ON CUSTOMER SAVINGS

Q. Mr. Casten, testifying on behalf of NEDGC, and others contend the Company's standby rates will reduce the savings otherwise available to distributed generation customers and deter "cost effective" self-generation technologies. Do you agree with this assertion?

A. Although the proposed standby rate may make some new DG alternative more expensive for a specific customer as compared to current rates, I don't agree with the second part of the assertion for the simple reason that providing standby service is not free and it requires the Company to incur costs that must be considered by a customer when making a decision to invest in self-generation equipment. When standby rates are consistent with the comparable costs for alternative distribution service, the customer will face an appropriate economic decision as to whether self-generation is a cost-effective alternative to purchasing generation service and having it delivered via normal utility distribution service. If the comparable cost of standby service were not fully reflected in the cost/benefit analysis used to determine the effectiveness of DG, cross-subsidies between standby and non-standby customers would be created and societal resources would be less efficiently allocated as a result.

Although a customer who was able to obtain standby service at little or no cost would obviously achieve more "savings," such a comparison does not provide a fair or accurate comparison because self-generation customers will nonetheless cause the Company to incur real costs necessary to provide the requested standby service. Given that those costs must be recovered, sound economic theory and standard regulatory practice support recovering such costs from the customer who caused the costs to be incurred.

Q. What has the Department said about its policies concerning the development of standby rates?

A. In the Department's Order opening its investigation into distributed generation, the Department emphasized that standby service tariffs should ensure that customers pay an equitable share of distribution system costs. The Department stressed the necessity that standby service tariffs avoid cost responsibility being shifted from DG customers to other customers, who are not responsible for them. According to the Department, standby service rates should provide an appropriate price signal to customers seeking to install distributed generation.

Order Opening Investigation into Distributed Generation, D.T.E. 02-38, at 4 (June 13, 2002). Based on these statements, the Department properly does not favor the cross-subsidization of standby rates in order to improve artificially the financial benefits attributable to distributed generation.

Q. Are the proposed standby rates an attempt by the Company to prevent the development of distributed generation?

A. Not at all. The Company supports distributed generation and has designed its proposed standby rates to reflect the same level of cost recovery for this service as is reflected in the otherwise applicable continuous service rate schedules because the underlying costs of providing the service are the same. Setting comparative prices for services that require the Company to incur the same costs promotes fairness and economic efficiency. If prices for standby service were artificially set at levels significantly lower or higher than those for continuous-use service, the differential costs and/or benefits seen by the potential DG customer would be distorted and would lead to uneconomic substitution of one service for another.

Q. Does NSTAR Electric support the development of DG as providing a benefit to its transmission and distribution system?

A. Yes. Distributed generation may have potential for providing some benefit to NSTAR Electric's distribution system in certain circumstances if there is lasting assurance that the Company will be able to avoid some level of additional distribution capacity that would otherwise be invested in by the Company for traditional distribution equipment. This assurance could be realized when multiple DG units operate independently on the same circuit without common-mode failure potential. It will likely take time for multiple DG units to develop on a single distribution circuit. However, the presence of those potential benefits in certain specific situations in the future does not obviate the need for a properly designed set of generally available standby rates to be established now that are structured to recover the costs associated with providing standby service. As described in the rebuttal testimony of Dr. Parmesano, distribution standby rates are not the right place to provide incentives for the installation of distributed generation, especially where such benefits may not be widespread or available in a majority of DG installations.

Q. Isn't it correct that current standby customers with on-site generation would pay more under the proposed standby tariff than they would pay under the Company's existing tariffs (absent grandfathering)?

A. Generally, under the Company's existing tariffs, customers obtain standby service under the otherwise applicable all-requirements distribution tariff. This means that they are billed based on monthly metered demand and energy usage, even though costs were incurred by the Company based on their full standby needs, not intermittent demand. As explained in my initial testimony, this approach leads to subsidization of standby service. The new tariffs apply the same rates, but bill based on contract demand. This will reflect a more equitable matching of the cost responsibility and cost incurrence so that customers that impose similar costs on the system contribute similar levels of revenues to support those costs. The costs are similar for two important reasons: (1) distributed generation has a finite probability of failure, thus the necessity for standby service; and (2) the distribution company must be assured that sufficient capacity exists on its distribution system at the time that service is required. Since the time and frequency of the need for distribution capacity to provide standby service is not known, sufficient reserve capacity must exist at all times. Thus, the costs for providing this service are equivalent to those required for continuous-load customers. If the costs are equivalent, it is reasonable for the revenue recovery to be similar. The pattern and level of annual billing quantities recorded on the Company's billing meter will be significantly different for a customer after the installation of on-site generation compared to the pre-installation pattern. Consequently, the pattern of revenue recovery will also change significantly if standby service is charged at rates applicable to continuous-use customers. The Company's proposal for using contract demand in its rate design is reasonable for maintaining revenue recovery consistent with cost incurrence.

Q. Mr. Vardakas, testifying for NEDGC, states that he believes that the Company's proposed standby rates will be too confusing to customers. Do you agree?

A. No. These customers are familiar with demand charges and are quite sophisticated. They are leading the way to renewables, combined heat and power ("CHP"), and other forms of self-generation. In fact, other intervenors in this proceeding have advocated much more elaborate rate-design alternatives in this proceeding.

LOAD RESEARCH DATA AND COST-OF-SERVICE STUDIES

Q. Mr. Pereira and Ms. Saunders argue that the Company's proposed standby rates are flawed because they are not based on a current cost-of-service study. Do you agree?

A. No. The most important issues concerning cost are whether the rates for standby customers are set in accordance with the corresponding rates for all-requirements customers and whether the standby rates are consistent with traditional ratemaking principles. The proposed standby rate design and rates were based on the existing distribution and transmission tariff rates for a comparable non-standby customer who otherwise purchases all of its electricity from either the Company or a third-party supplier. Establishing the rates in this manner assures that a standby customer receives an accurate price signal regarding the relative cost of standby service and the continuous-use service.

If standby service was priced separately using a different costing methodology or using costs from a different time period than that used for the equivalent continuous service rate, artificial rate savings would result, thereby distorting the cost/benefit economic factors used to evaluate the project. Consistency between the standby rate and the otherwise applicable rate promotes fairness and economic efficiency. Bill savings that might result because costing methods used to calculate prices were different for the comparable rates would distort the analysis of the economic viability of installing DG.

Q. How do you respond to Mr. Lively's contention that the Company lacks the necessary load research data to support its standby tariffs?

A. As described in the rebuttal testimony of Mr. Salamone, for the most part, the distribution system must be constructed in the same manner and configuration (and with the same materials) whether or not a customer is able to generate its own electricity. As a result, the actual load pattern of the customer with on-site generation provides no additional information needed for pricing the standby service. For existing customers, the historical load shape existing before the installation of on-site generation is the basis for determining the otherwise applicable rate schedule and the equivalent standby rate. For a new customer with installed on-site generation, estimates of the total connected load and internal diversity factors provide the necessary information for determining the otherwise applicable rate schedule as is the usual practice when setting up a new customer account. Load research for standby customers will provide information only regarding the pattern of metered billing quantities used for revenue recovery. With sufficient history of changes in the pattern of metered billing quantities, as well as potentially increased diversity of DG facilities on individual distribution circuits, the Company may in the future have information useful to review its design of standby rates and it intends to monitor such data closely. However, at this point in time, there is no diversity among DG loads on the Company's system and the Company designs its distribution system in the same manner for such firm, but intermittent, loads as it does for all-requirements customers.

Q. Mr. Lively suggests that customers with DG are likely to have "better load research characteristics" than do customers without distributed generation (page 15). Do you agree?

A. No, as described in the rebuttal testimony of Mr. Salamone, the Company's distribution system is largely planned on a non-coincident peak basis. Mr. Lively's testimony describes the relationship between load factor and coincidence factor with the assertion that low load factor customers tend to have low coincidence factors. He goes on to assert that, since high coincidence translates to high costs, low coincidence should translate to relatively lower cost to serve. Since distribution planning relative to on-site generation relies on non-coincident loads, this argument is irrelevant and is negated by the manner in which prudent utility planning must be performed.

Even if it mattered (which it doesn't), DG customers may have fuel cost incentives occurring all at the same time. For example, this may occur when natural gas prices are high enough for the customer to forego generation in order to profit from selling gas in the market. This could result in their simultaneous reliance on standby service even if natural coincidence is low.

Q. Ms. Saunders contends that many non-DG customers share the same variation in load that DG customers do. Do you agree?

A. No. Ms. Saunders has provided frequency tables of the ratio of customer's minimum to maximum monthly billing demand in a single year (Elaine

Saunders testimony at page 4, Information Request DTE-TEC 1-2). Ms. Saunders contends that, because there are some non-DG customers at the lower end of the spectrum of ratios, these customers are as intermittent as DG customers taking standby service. As described below, this billing demand ratio is not appropriate for the purpose of determining intermittence when comparing DG and non-DG customers.

Q. **Please explain why the annual billing demand ratio is not the appropriate reference point for comparing standby customers load patterns to non-standby customers.**

A. The Min/Max billing demand ratio is not appropriate for comparing load patterns between DG and non-DG customers because this ratio of extreme loads does not adequately measure the overall variability of customers' loads throughout a year. In a given year, non-DG customers may exhibit a few very low billing demand months for a number of reasons such as annual vacation shutdowns, partial month billing when initiating service, leaving service or exchanging service, etc. Conversely, DG customers with load following or base load operating schedules will typically exhibit a few months with relative load spikes. The level of the load spike will be a function of the percentage of the customer's total internal load that is usually served by the DG capacity. The Min/Max ratio for both types of customers described above is likely to be low. However, their 12-month billing demand pattern will be starkly different. In point of fact, for a non-DG customer with a low load factor, it is still likely that such a customer will impose some level of demand each month on the

Company's system and that the customer will thereby pay a monthly demand charge in each month of the year. This is not the case for a more typical DG customer where its generating facility will more often be available to serve the customer's base loads and avoid any demand charge for that load in a majority of months.

A more accurate measure to compare demand billing patterns is to calculate the ratio of Average/Max billing demand (where the average demand reflects the customer's usage throughout the year for customers who were on the system for the entire year). However, because the sample of customers with on-site generation is so small, it is difficult to infer load pattern differences with great precision. This is further complicated by the differing percentages of DG capacity to total customer load within the sample. What we do have some certainty about is the fact that the DG customer who desires firm standby service will require intermittent, infrequent and unscheduled service from the distribution system for that portion of its internal load and that distribution capacity must be built and placed in reserve to serve that load whenever it is needed.

Q. Have you developed data regarding the distribution of Average/Max billing demand ratio for the other applicable rate schedules?

A. Yes. Exhibit NSTAR HCL-8 sets forth charts that indicate the frequency histograms for Boston Edison, Commonwealth and Cambridge, respectively. These charts indicate that there are very few customers with billing ratios at the low end of the spectrum of values. Intervenors have characterized large DG as being very reliable. This high reliability would translate to very low billing ratios for the standby load normally supplied by the on-site generation if such load were billed on an as-used basis. Consequently, it would be reasonable to expect that a frequency histogram of a large sample of DG installations would be concentrated at the low end of the Average/Max billing ratio chart.

Q. **Will similar annual billing demand ratios cause a utility to over-collect from customers with distributed generation relative to customers without distributed generation, as suggested by Ms. Saunders and Mr. Lively? Please explain.**

A. No. Most customers will install DG to satisfy base load requirements. The combination of supplemental billing demands and the standby contract demand is unlikely to exceed the billing demands the customer would incur without the DG (see Information Request NEDGC-2-10(Supp)). Under this structure, the contract demand will not exceed the lowest monthly billing demand. Thus, there will be no over-collection from customers. Furthermore, because the cost of providing the distribution standby service is essentially the same for a DG customer as for a non-DG customer, subsidies will exist for grandfathered DG customers who are subject to only as-used demand charges. The Company's proposed standby rates will protect against further subsidization as additional DG develops.

Q. Ms. Saunders notes that the random nature of the outages of distributed generation makes them less expensive to serve instead of more expensive. Do you agree with this?

A. No. As explained in the rebuttal testimony of Mr. Salamone, DG outages may be random, but the Company plans for non-coincident peaks of all customers, including those with DG. Also, as explained above, although production schedules may vary, fuel costs are generally the same, and many DG customers may elect to lean simultaneously on backup service and sell fuel at attractive market prices. Consequently, such incentives could very well cause outages to be coincident for DG customers with the same fuel sources. The same scenario can occur for those DG facilities that rely on wind or solar to generate electricity depending on the availability of sufficient wind or sun resources to power the DG equipment.

Q. Mr. Lively and others maintain that the use of an annual contract demand level constitutes an improper ratchet, which allows for improper revenue over-collection. Is this a fair concern?

A. This critique of contract demand inherently stems from the incorrect assertion that the intermittent standby load costs less to serve than the more continuous load of the non-DG customer. The Company has shown that its distribution planners rely on non-coincident load when planning for distribution circuits (and substations for serving large customers). This means that the costs of these facilities are the same for DG and non-DG customers with the same maximum internal load. However, because the annual demand billing quantities for the DG customer will be far less than those for the non-DG customer, fairness requires that a contract demand should apply to the DG customer in order to recover the equivalent revenue.

The contract demand rate-design mechanism has been characterized by some as an improper ratchet. However, this rate design tool is an equitable and useful tool to match revenues with the cost of providing service. As explained by Dr. Parmesano, a company's distribution system is composed of fixed assets whose costs do not vary once the assets are in place. The size and capacity of the elements of a distribution system are based upon the maximum potential load the system must carry taking into consideration appropriate contingencies. Distribution demand rates are generally stated as $/kW-month or $/kVA-month. When monthly customer demands vary significantly from the maximum demand, revenue recovery will not track cost incurrence effectively. Thus, it is proper to establish contract demands as part of the design of standby rates to assure appropriate revenue recovery.

The Department has not generally approved the use of annual demand ratchets in the design of rates in the past. However, this approach reflects earlier rate design methods before industry restructuring when utilities were vertically integrated and providing energy supply service as well as transmission and distribution ("T&D") services. Prior to restructuring, demand rates included the marginal costs of production, transmission and distribution in one monthly integrated charge. Production and transmission costs constituted a majority of the demand charges. At that time, ratchets were deemed inappropriate, as the argument goes, because once a maximum demand was established customers had no incentive not to consume up to that maximum for the remainder of the billing period. An annual ratcheted demand that was subject to the high integrated monthly demand price apparently dwarfed any incentive that customers might have to avoid variable energy charges by reducing consumption.

However, with the advent of restructuring and the unbundling of production and transmission costs from distribution costs, demand charges are reduced significantly from prior integrated levels. At the same time, variable energy charges have increased significantly while reflecting total market-based production costs. Thus, there now exists a greater bill-reduction incentive to reduce consumption. Consequently, the cost tracking benefits of rate designs that include demand ratchets or contract demands outweigh any negative incentives to reduce consumption.

Q. Mr. Vardakas, testifying for NEDGC, maintains that standby customers will be "double charged" because the Company has improperly assumed that DG will go out of service at the time of the Company's system peak ([page 8). Is this conclusion correct?

A. No. The distribution system is built to serve customer non-coincident demand reflecting the potential that the customer's DG will not be available at the time of the distribution circuit peak. This is not "double charging," but rather, it is prudent planning. The proposed standby rates are simply designed to recover equitably distribution-related costs from standby customers in an economically efficient manner.

Q. Mr. Vardakas states that other general service customers have comparable loads that are only sometimes used, causing an occasional increase in their peak demand billing. He argues that those customers are not required to pay a monthly capacity or standby charge. Do you agree with this reasoning?

A. No. An outage of a small DG unit is not the same as adding additional occasional load like air-conditioners when it gets hot. The load variability is very different. For one thing, loads such as air conditioning loads are highly predictable (i.e., they occur for certain hours during the hot, summer months). On the other hand, the unscheduled outages of DG facilities are not nearly as predictable. Moreover, DG outages are in addition to the normal load variability like that associated with air conditioning. Since DG is most economical for satisfying the base load portion of a customer's internal load, the variability associated with generator outages is in addition to the variability of the customer's supplemental service, which would reflect loads like air conditioning. Accordingly, the planning process and rate mechanisms applicable to air conditioning loads and DG customers are not comparable.

Q. Mr. Michelman, testifying for Conservation Load Foundation and the Solar Energy Business Association of New England, argues that the Company's proposal to shift costs from the energy charge to the demand charge reduces incentives to install larger rather than smaller wind turbines (pages 7-8). What is your response to this criticism of the Company's rate design?

A. Because the distribution-related costs necessary to serve DG customers are fixed, and standby customers' use is intermittent, cost-based rate design requires that all distribution costs be reflected in the demand charge, rather than leaving some portion of the total distribution costs in the energy charge. This rate design is necessary regardless of the size of the DG equipment.

Q. Mr. Michelman concludes that the proposed standby rate structure provides a disincentive to customers with lower load factors to install wind turbines (page 10-11). Do you agree?

A. No. This is always the case for a customer paying demand charges who has a low-load factor. The current energy charges do not reflect actual cost causation. As stated above, fixed costs should be recovered in fixed component of the rate. Moreover, for certain DG technologies such as wind and solar, their low capacity factor of such generators makes it likely that such customers would experience a demand charge on a monthly basis, even if they were served under the otherwise available rate. Thus, to the extent that customers desire firm standby service, the proposed standby rate should not have a large effect on the economics of those types of renewable DG technologies.

Q. Ms. Saunders argues that by and large the distribution system is a shared resource and that at the substation level, loads are an aggregation of the loads of many customers (page 7). Isn't there some diversity among customers that would have the effect of reducing the fixed costs based on a non-coincident peak?

A. Only to a limited degree for certain customers. Consistent with the testimony of Mr. Salamone and Dr. Parmesano, the Company proposes to modify its standby rate design to recognize a level of diversity of customer load at the distribution substation level for those on-site generators that have nameplate capacities under 1 megawatt ("MW"). The Company proposes to revise the demand charges applicable to the contract demand for customers with generation units of less than 1 MW by a factor equal to the percentage of substation investment to total distribution investment. The effect of this change for smaller DG installations is to remove substation costs from recovery by means of the contract demand. The revised rates will recover substation costs through the supplemental demand charges on an as-used basis. Yet, for other elements of the Company's distribution system where system planning is based upon the non-coincident loads of all customers, the contract-demand mechanism would still apply. Exhibit NSTAR-HCL-9 sets forth the calculation of the substation investment percentages for each company. Exhibit NSTAR-HCL-10 sets forth the revised tariffs reflecting the revised prices for standby service. In addition to the changes in the demand charges, the Company revised the rate provisions associated with the credits to the supplemental demand billing quantities that are required when the customer's on-site generating unit experiences an outage or reduction in output.

However, as explained in the rebuttal testimony of Mr. Salamone and Dr. Parmesano, for DG installations of 1 MW or greater, the material size of those installations requires that, as a matter of prudent planning, the Company size its substations to accommodate these larger loads compared to the loads of smaller customers at the substation level. Thus, for these larger DG customers, the use of a contract demand to recover the fixed distribution costs (including distribution substation costs) incurred in providing firm service is reflected in the Company's proposed standby rates.

Q. **Mr. Greene, of the Solar Energy Business Association of New England, contends that reassigning distribution-related costs from the current per-kWh charge to a higher distribution demand charge will result in rate equity issues between similarly situated customers facing different rates. Is this a concern?**

A. No. From the perspective of the distribution system, a distribution company incurs the same cost to serve and the same revenue requirement, thus an equivalent level of costs need to be recovered from each type of customer. The different rate design for the proposed standby rate is a function of the difference service use patterns and resulting billing determinants, but it is intended to maintain equity between DG customers and all-requirements customers instead creating cross subsidies, which would be unfair to other customers for whom DG is not a viable option.

Q. Mr. Greene suggests that, if a standby rate is adopted in this proceeding, the rate should be designed to provide safeguards against DG-related revenue erosion only when there is a severe adverse impact consistent with the "exit fees" parameters in c. 164, § 1G(g). Do you agree with this approach?

A. No, I do not. The statute referred to by Mr. Greene concerns the application of exit fees, and does not address an electric company's general service tariffs, including standby rates, for continuing service to customers. The statutory provision does not provide even a useful analogy to the Company's proposed tariffs. Standby service is not an exit fee. Customers receive the use of the Company's distribution system, which is in a constant state of readiness to serve standby customers. Moreover, a customer is not required to take standby service. Unlike an exit fee, if a customer doesn't want firm standby service, a customer is not required to take it. Even aside from issues of revenue recovery, the proposed standby rates are intended to provide the proper economic signal for customers comparing their electricity costs versus the otherwise available rate in the context of a potential DG installation. This issue is completely distinguishable from the concept of an exit fee.

Q. In his testimony, Mr. Greene seems to argue for an exemption for renewable sources of power relative to standby service rates based upon contract demand. Do you agree with this approach?

A. From the perspective of economic theory and cost incurrence, there is no reason to offer renewable sources such as wind and solar exemptions from standby service rates, where these renewable generation resources request firm standby service from the distribution company. In addition, as stated above, because wind and solar resources will generally impose a demand on the distribution system each month, it is unlikely that charging for standby service via a contract-demand structure would significantly affect the economics of such projects. Nevertheless, this is a policy matter for the Legislature and the Department to consider, which the Company believes is an issue independent from the proper design of standby rates in most circumstances.

STANDBY TARIFF TERMS AND CONDITIONS

Q. Why isn't there a separate tariff for maintenance service?

A. Maintenance, even if performed during off-peak periods, does not relieve the customer of its overall standby obligation to pay for the fixed costs needed to provide a standby service customer's non-coincident peak distribution requirements. When electric companies were vertically integrated, a separate maintenance service was offered that provided a self-generation customer with electric energy as well as the capacity to continue operations during planned maintenance periods. However, in today's unbundled environment, maintenance service is now a distribution service only, and the distribution costs attributable to providing a standby customer's overall standby service now include the recovery of standby maintenance service costs.

Q. Why should all meters be owned and operated by NSTAR Electric?

A. As with its other rates, the Company needs to have control over meters to assure their accuracy. In addition, the design of the proposed standby rates requires that the Company have knowledge of the output of the generator in order to determine the billing determinants for the rate. Without this information, the Company would not be able to determine the level of supplemental load that it was providing to the customer. This information is a necessary component to accurately calculate bills under the proposed rate.

Q. Why is six months notice requirement to cancel necessary?

A. As described in the rebuttal testimony of Mr. Salamone, there is a long lead time associated with the installation and life expectancy of an electric distribution system. In fairness to all other customers, the Company should be allowed the greatest opportunity to recover its sunk costs by requiring a customer to provide six months of notice before terminating service. In fact, the six-month notice is identical to that for the otherwise applicable rate schedule.

Q. Why doesn't the Company grandfather all projects that were under consideration before the filing date?

A. The Company proposes that its new standby tariffs will be applicable only to customers who begin satisfying all, or a portion of, their internal electric load requirements from their own generation facilities *after* the effective date of the Company's proposed tariffs. Where a customer was generating electricity *before* the effective date of the Company's proposed standby tariffs, and therefore had no notice of the applicability of the tariffs, the customer will be "grandfathered" from the application of the new tariffs.

If, on the other hand, a project is only in a planning stage and is not online, the Company believes that it is appropriate for the project to be evaluated the economics of its self-generation in the context of the Company's proposed standby tariffs because the tariffs more accurately reflect the actual economic cost that standby service imposes on the system, and properly therefore, on the customer. It is necessary to establish a clear line concerning the applicability of the Company's proposed standby tariffs to prevent the "slippery slope" that inevitably will occur between those contemplating or otherwise in the planning stages and those facilities that are in actual operation. Under the Company's proposal, customers who intend to self-generate in the future will have sufficient notice of the Company's standby tariffs to make an informed economic decision whether to proceed.

Q. Ms. Saunders has raised a concern about the application of the proposed standby tariffs for customers with multiple DG units (page 10). Is her concern valid?

A. Not really. Although it may be true that, for a customer that has multiple DG units, there could be diversity among DG units, the key issue is the level of firm standby service capacity a customer requires. For example, if hypothetically there were a customer with a peak load of 6 MW, and it elects to install three 2 MW DG units, the Company is willing to reach mutual arrangements with the customer regarding the amount of firm standby capacity it seeks. However, these situations would be limited to where the customer has multiple DG units at its location and the Company is satisfied that the customer will operate its multiple DG facilities in a staged manner (i.e., with one or more of the DG units held in reserve for backup purposes). To the extent that the customer wants 6 MW of firm standby capacity, the Company would build and maintain its distribution system to serve that potential 6 MW load, and the customer should be required to pay a 6 MW contract demand. If a smaller amount of firm standby service is mutually agreed upon (e.g., 2 or 4 MW), the customer would pay a contract demand based on the nominated level of service; however, the Company would be obligated to provide firm standby service only for that smaller nominated level. The balance of the customer's load, if it were needed to be served by the Company, would be served as an interruptible load on an as-available basis. The Company would need to maintain an enforceable, technical ability to shut down immediately the customer's load above the firm level of standby service.

One further point of note needs mentioning here. To the extent that the customer's DG units are of the same technology and are susceptible to common-mode failure as a result of fuel unavailability or other related economic or operational contingencies, the customer would be well advised to nominate the full peak load as its standby contract demand even given potential "diversity" among multiple DG units. Otherwise, the customer may be at risk for periods of shut down at its facility.

Q. Mr. Lively argues that the Company's interruptible rate proposal is discriminatory and not cost-based. Do you agree?

A. No, the Company views the availability of interruptible standby arrangements as an important customer alternative and will endeavor to negotiate such contracts whenever desired by customers. Such contracts can provide economic benefit to certain customers who are able to discontinue their operations for periods of time when distribution service cannot be provided on a firm basis. The Company believes that special contracts are the appropriate means of dealing with the specific circumstances that would arise in the context of non-firm service such as notice, communications protocols with the customer, potential disconnect scenarios and penalties for non-compliance. It should be also remembered that the Department has a long history of using interruptible service as an opportunity service to obtain the maximum contribution possible toward a company's fixed costs. See Boston Gas Company, D.P.U. 93-60, at 320 (1993), citing Gas Transportation, D.P.U. 85-175, at 31 (1987); Boston Gas Company, D.P.U. 88-67, Phase I, at 325-326 (1988).

Q. Does the Company have any further changes to make to its proposed standby tariffs at this time?

A. Yes. Cambridge's Rate SB-1 and Rate MS-1 have been modified to include a transition charge in compliance with the Department's recent approval of such a change. Cambridge had filed for this change after noticing that it had inadvertently omitted this charge from its compliance rates previously filed for effect January 1, 2004 in proceeding D.T.E. 03-118. Also, Cambridge is modifying its proposed Rate SB-2 and Rate SB-3 to reflect the appropriate treatment of the demand charges for the first 100 kVA block under its supplemental pricing proposals. The effect of this change is that the demand charge for the first 100 kVa applies only to the contract demand kVA and not to the supplemental demand kVA. Boston Edison has revised its proposed Rate SB-2 to account for the appropriate treatment of the first 10 kW of demand for the same reasons described above for Cambridge's rates. Further, to address situations in which a DG facility represents a small portion of a customer's overall load, the Company has modified its proposed rates to include a 20 percent threshold (i.e., the size of the DG unit compared to the customer's annual peak load) for the applicability of standby service. Please see Exhibit NSTAR-HCL-10, which includes these tariff revisions. In addition, as described above, Exhibit NSTAR-HCL-10 sets forth revised tariffs for each company that reflect an as-used demand charge for standby service for customers having DG units up to 1 MW in size that recognize load diversity at the substation level.

Q. Does this conclude your testimony?

A. Yes, it does.